National Energy Board

Office national de l'énergie

Short-term Canadian Natural Gas Deliverability

2008-2010



AN ENERGY MARKET ASSESSMENT OCTOBER 2008

Canada

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Cat. No. NE2-1/2008E
ISBN 978-1-100-10857-5

This report is published separately in both official languages. This publication is available upon request in multiple formats.

Copies are available on request from:
The Publications Office
National Energy Board
444 Seventh Avenue S.W.
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1-800-899-1265
Internet: www.neb-one.gc.ca

For pick-up at the NEB office:
Library
Ground Floor

Printed in Canada

N° de cat. NE2-1/2008F
ISBN 978-0-662-09971-0

Ce rapport est publié séparément dans les deux langues officielles. On peut obtenir cette publication sur supports multiples, sur demande.

Demandes d'exemplaires :
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Internet : www.neb-one.gc.ca

Des exemplaires sont également disponibles à la bibliothèque de l'Office :
Rez-de-chaussée

Imprimé au Canada

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CAPP	Canadian Association of Petroleum Producers
CBM	coalbed methane
CGPC	Canadian Gas Potential Committee
EMA	Energy Market Assessment
ERCB	Energy Resources Conservation Board
LNG	liquefied natural gas
NEB	National Energy Board
NGLs	natural gas liquids
PSAC	Petroleum Services Association of Canada
SOEP	Sable Offshore Energy Project
U.S.	United States
WCSB	Western Canada Sedimentary Basin

Units

Bcf	= billion cubic feet
Bcf/d	= billion cubic feet per day
GJ	= gigajoule
m^3	= cubic metres
m^3/d	= cubic metres per day
Mcf	= thousand cubic feet
Mcf/d	= thousand cubic feet per day
MMcf	= million cubic feet
MMcf/d	= million cubic feet per day
Tcf	= trillion cubic feet

Conversion Factors

1 million m^3 (@ 101.325 kPaa and 15° C) = 35.3 MMcf (@ 14.73 psia and 60° F)
All dollar amounts are quoted in Canadian dollars.

FOREWORD

The National Energy Board (the NEB or the Board) is an independent federal agency that regulates several aspects of Canada's energy industry. Its purpose is to promote safety and security, environmental protection and efficient infrastructure and markets in the Canadian public interest within the mandate set by Parliament in the regulation of pipelines, energy development and trade. The Board's main responsibilities include regulating the construction and operation of interprovincial and international oil and gas pipelines as well as international and designated interprovincial power lines. The Board regulates pipeline tolls and tariffs for pipelines under its jurisdiction. In terms of specific energy commodities, the Board regulates the exports and imports of natural gas as well as exports of oil, natural gas liquids (NGLs) and electricity. Additionally, the Board regulates oil and gas exploration, development and production in Frontier lands and offshore areas not covered by provincial or federal management agreements. The Board's advisory function requires keeping under review matters over which Parliament has jurisdiction relating to all aspects of energy supply, transmission and disposal of energy in and outside Canada.

The NEB monitors energy markets to objectively analyze energy commodities and inform Canadians about trends, events and issues. In the past year, the Board issued a number of Energy Market Assessments (EMAs) on a wide range of energy commodities. In addition, the Energy Pricing Information for Canadian Consumers section on its website provides an additional means to keep Canadians informed on energy market developments.

This EMA report, titled *Short-term Canadian Natural Gas Deliverability, 2008–2010*, examines the factors that affect gas supply in the short term and presents an outlook for deliverability through 2010. The main objective of this report is to advance public understanding of the short-term gas supply situation in Canada. This report is an update to the Board's October 2007 EMA, titled *Short-term Canadian Natural Gas Deliverability, 2007-2009.*

While preparing this report, the NEB conducted a series of informal meetings and discussions with drilling companies, natural gas producers, pipeline companies, and industry associations. The NEB appreciates the information and comments provided and would like to thank all participants for their time and expertise.

If a party wishes to rely on material from this report in any regulatory proceeding before the NEB, it may submit the material, just as it may submit any public document. Under these circumstances, the submitting party in effect adopts the material and that party could be required to answer questions pertaining to the material.

Questions and comments regarding this EMA can be referred to:

Paul Mortensen telephone: 403-299-2712, email: paul.mortensen@neb-one.gc.ca

Executive Summary

Canadian natural gas is an important part of the North American gas market, providing about 25 percent of combined U.S. and Canadian production for the past several years. The value of producers' sales for Canadian marketable natural gas in 2007 was $39 billion.[1] This report provides an outlook for Canadian gas deliverability (the ability to produce gas from new and existing wells) to the end of 2010.

Canadian gas deliverability remained within a narrow range from 2000 to mid-2007 at around 483 million m^3/d (17.1 Bcf/d) and has since begun to decline. Approximately 98 percent of the total Canadian volume comes from the Western Canada Sedimentary Basin (WCSB) with most of the rest from Atlantic Canada.

Deliverability expectations for the WCSB in the short term are uncertain. Drilling and development activity in the WCSB hinges primarily on the price of natural gas in the North American market relative to the costs incurred. That price is volatile, influenced by uncertainties such as weather-driven market demand, changes in North American natural gas supply, cost, relative attractiveness of other basins, competition with oil-related projects, availability of imported liquefied natural gas (LNG) and possible supply disruptions in the Gulf of Mexico.

Since the Board's 2007 report,[2] shale gas and tight gas prospects in the Horn River and Montney plays of northeast B.C. have attracted significant interest from Canada's upstream industry. Favourable test results reported from initial wells, major interest in land sales and open seasons for new pipeline capacity are all indications of the potential significant impact on deliverability from these areas.

Interest in shale gas in Canada follows upon the success of shale gas developments in the U.S. The largest concentration of interest is occurring in northeast B.C., but early stages are also underway in Quebec and the Maritimes. While having massive potential, the viability of large scale commercial development in Canada has yet to be proven. The contribution of shale gas over the period to 2010 is likely to be constrained by the need to test alternatives, assess viability, optimize operations and build the infrastructure needed to move the shale gas to major pipelines.

For at least the last decade, new wells drilled in the WCSB have tended to decline at similar rates over their productive lives as previous wells, but with a production level at start-up that tends to be lower each year. With the initial productivity from similar wells decreasing from year to year, natural gas producers in Canada were maintaining overall deliverability by increasing the number of wells drilled annually. Improving technology and relatively high North American natural gas prices encouraged producers to invest, even though costs to develop and produce new gas supplies were also rising.

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1 Canadian Association of Petroleum Producers estimate.

2 NEB EMA, *Short-term Canadian Natural Gas Deliverability 2007-2009*, Available at www.neb-one.gc.ca.

After peaking in late 2005 because of hurricane-related supply disruptions in the U.S. and an early start to that winter, market prices for natural gas declined roughly 60 percent by the fall of 2007. Over the same period, oil prices were rising and activity related to oil and oil sands began to draw investment away from natural gas in Canada while continuing to apply upward cost pressure for labour, equipment and materials. The squeeze from falling prices and rising costs caused Canadian natural gas drilling to slow. Buoyed by the delayed start-up of wells drilled during the earlier peak, deliverability held steady for another year after drilling slowed, but by 2008 was roughly 28 million m^3/d (1 Bcf/d) below the previous year.

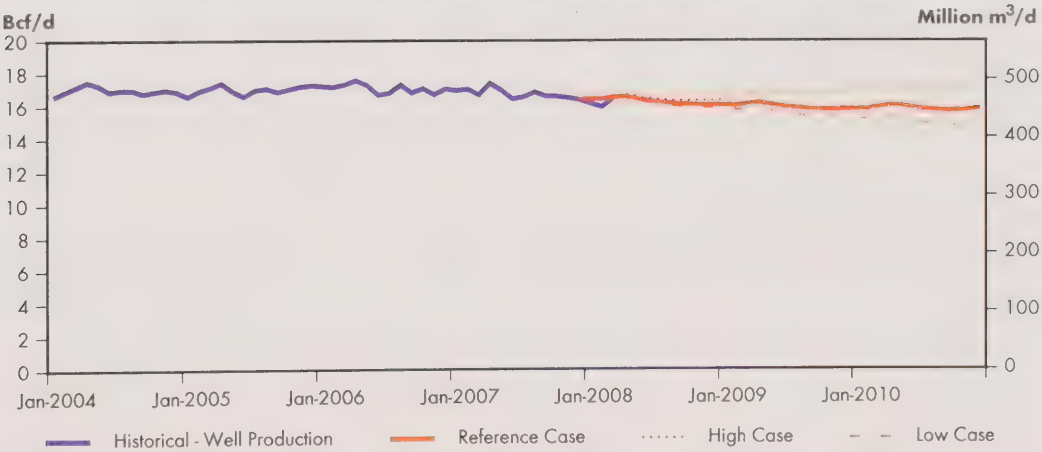
As oil prices surged and less LNG was imported into North America, natural gas prices more than doubled through the first half of 2008, but then gave up most of these gains over the summer. A key factor in the price decline has been the roughly 8 percent growth in U.S. natural gas production between 2007 and 2008.[3] This extreme price volatility makes it difficult for producers to make investment decisions and may result in a more cautious approach to natural gas plans for the rest of 2008 and into 2009 and 2010 than might have been the case when prices were rising earlier in the year.

To reflect the short-term uncertainty of the North American natural gas market, deliverability in this report is projected under three cases intended to reflect different levels of drilling investment that may occur: Reference Case, High Case and Low Case.

In the Reference Case, average annual deliverability is expected to slip from 477 million m^3/d (16.9 Bcf/d) in 2007 to 450 million m^3/d (15.9 Bcf/d) in 2010. Under the reduced drilling of the Low Case, deliverability is projected to decline to 426 million m^3/d (15.0 Bcf/d). After falling in 2008, deliverability is projected to increase in 2009 and 2010 in the High Case and average 489 million m^3/d (17.3 Bcf/d) by 2010 (Figure ES.1).

With Canada's large natural gas resource base and ongoing efforts to further enhance innovation and efficiency, Canadian natural gas deliverability is expected to continue to make a key contribution to North American natural gas supply.

Outlook for Canadian Gas Deliverability – Reference, High and Low Cases



3 U.S. Energy Information Administration, U.S. Dry Natural Gas Production http://tonto.eia.doe.gov/dnav/ng/hist/n9070us1m.htm

Introduction

Canadian natural gas supply continues to have enormous potential, with a large remaining conventional natural gas resource base,[4] coalbed methane (CBM), shale gas and the prospect of development of additional northern and offshore resources in the future. Canadian natural gas supply also faces a number of challenges including a recent decline in output, upward cost pressures, competition for capital from oil and oil sands projects, and competition for investment with U.S. natural gas regions that are experiencing rising production. Price volatility has become a key issue with movements where market prices can double or fall by half at increasing frequencies.

In the absence of ever higher drilling levels, Canadian production began to decline in 2007. A return to the previous strategy of routinely exceeding the drilling level of the previous year may not be a viable future strategy because of the cost inflation this generates. An alternative approach that may turn out to be effective would see industry drill fewer wells but have more of these be higher productivity wells in unconventional "resource plays". With Canada accounting for just under one-quarter of the natural gas supplied to North America in 2007, there is considerable interest in the short-term outlook for Canadian gas deliverability. The primary objective of this report is to provide the Board's current outlook for Canadian natural gas deliverability to the end of 2010.

Chapter 2 provides background on the sources of Canadian supply, including a description of the geographic extent and nature of the supply in the various regions.

Chapter 3 provides a discussion of recent production and development trends, and includes a review of costs associated with development and production of new gas supplies in western Canada.

Chapter 4 contains a discussion of the three cases under which Canadian deliverability was assessed. The high volatility of natural gas prices in recent years, rising costs, and competing investment opportunities in oil, oil sands, and U.S. natural gas can contribute to variability in drilling investment in Canada. Three cases have been created to reflect this uncertainty—Reference Case, High Case and Low Case. The rationale surrounding the three cases is described in this chapter.

Chapter 5 briefly describes the methodology used to estimate Canadian gas deliverability, and points to the detailed discussion on the methodology and parameters impacting deliverability that are available in the Appendices.

The Board's outlook for Canadian natural gas deliverability is presented in Chapter 6. The conclusions of the assessment are discussed in Chapter 7.

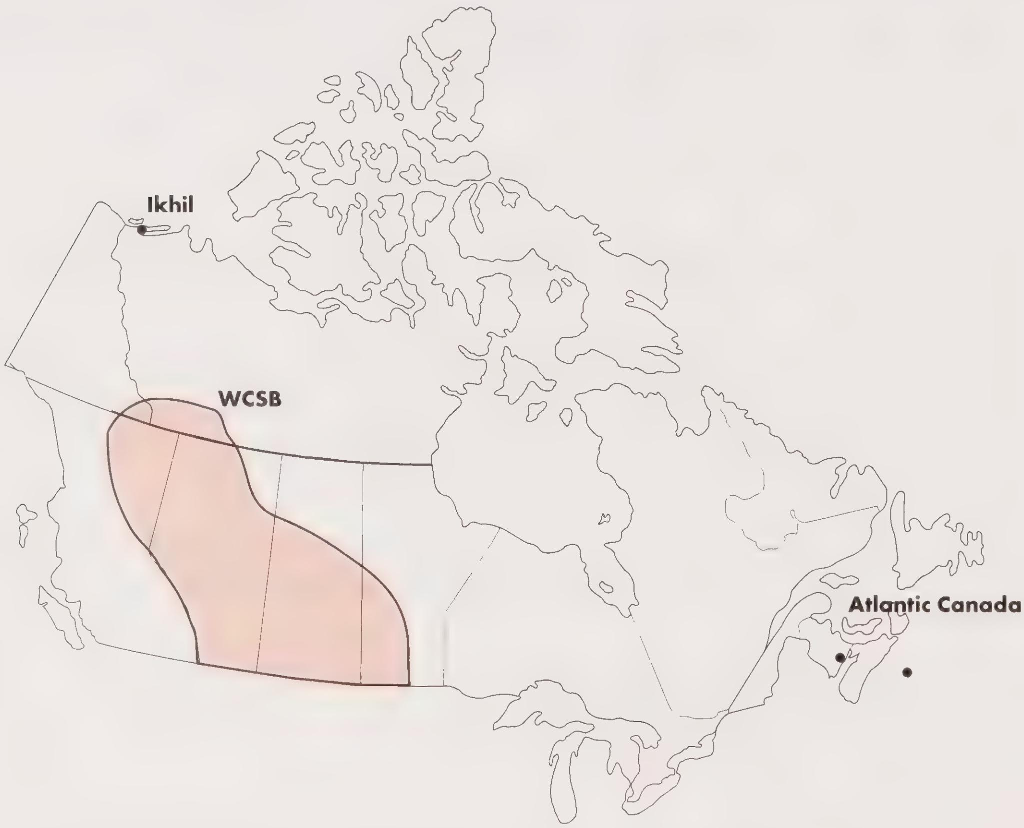
4 National Energy Board EMA, *Northeast British Columbia's Ultimate Potential for Conventional Natural Gas*, 2006. Available at www.neb-one.gc.ca.

BACKGROUND

The WCSB is Canada's main source of marketable gas production and currently accounts for 98 percent of total Canadian production. Natural gas production from Atlantic Canada started at the end of 1999 and provides most of the remaining gas production in Canada.[5] Figure 2.1 shows the location of these gas producing areas. A discussion of the production sources and major developments for each region is included in this chapter.

The Canaport terminal in New Brunswick is the only LNG import terminal under construction in the country. Other prospective LNG import projects in Atlantic Canada, Quebec and British Columbia are at various stages of consideration or development. Since gas supply for LNG projects

Canadian Gas Producing Areas



5 In addition to the WCSB and Atlantic Canada, a small amount of gas production also occurs in central Canada and in more northerly areas of the Northwest Territories.

is sourced from outside the country, these projects will not be covered in this report of Canadian gas deliverability.

2.1 WCSB

The WCSB underlies most of Alberta, significant portions of British Columbia and Saskatchewan, as well as parts of Manitoba and the Yukon and Northwest Territories (Figure 2.1). Alberta accounts for the largest share of gas production from the basin at roughly 80 percent. British Columbia and Saskatchewan provide roughly 16 and 4 percent of the total, respectively. The Yukon and Northwest Territories currently contribute less than 1 percent of WCSB production, and there is no gas production in Manitoba.

In this analysis, gas production in the WCSB is broadly split into conventional, CBM and shale gas categories. Within the conventional gas category, a sub-category of tight gas has been identified. The tight gas, CBM and shale gas categories are described in the following sections.

There are large regional differences in physical and producing characteristics in the WCSB, and as such, the basin is divided into smaller areas with similar characteristics for production decline analysis. In the past, the NEB used the geographical classifications of the Petroleum Services Association of Canada (PSAC)[6] for its WCSB breakdown. In this study, regions are broken down based on categories specifically selected to be reflective of similar costs. These classifications were originally developed by the petroCUBE[7] information service that provides well costs and performance data and then modified by the NEB. The modified[8] regional breakdown is shown in Figure 2.2.

Within each region the producing formations are grouped on a geological basis. Parameters for an average well in each region and formation are estimated and include initial production, production decline curve parameters, average depth, gas composition, shrinkage and success rate. Gas connections are grouped by connection year for the assessment of producing characteristics and deliverability.

WCSB Conventional Resources

Conventional gas production is the mainstay of gas deliverability in the WCSB, accounting for about 96 percent of total gas production from the basin.

WCSB Conventional Resources - Tight Gas

A significant amount of WCSB conventional gas production is produced from low permeability reservoirs that are identified in this analysis as "tight gas". At present, tight gas in Canada is not generally defined, nor is it typically distinguished from conventional gas as in the U.S. For this analysis, tight gas has been identified based on the plays defined by Forward Energy Group Inc.[9] The areas of tight gas recognized in this study include: certain Cretaceous zones in the Deep Basin; the Milk River, Medicine Hat and Second White Specks formations in southeast Alberta and southwest Saskatchewan; the Jean Marie group in northeast B.C.; and the Montney region in northeast B.C. Under this representation, tight gas comprised approximately 30 percent of total production in the

6 Petroleum Services Association of Canada - www.psac.ca/.

7 petroCUBE, from GeoLogic Systems Ltd. – www.petrocube.com. petroCUBE data is used and published with permission from GeoLogic.

8 Saskatchewan, under petroCUBE, was considered as one whole region. For this study the province was split into three gas-producing regions – West Saskatchewan, Southwest Saskatchewan and Eastern Saskatchewan.

9 http://www.forwardenergy.ca

WCSB Regional Map

Source: petroCUBE

WCSB in 2007. In future, lower permeability formations are increasingly likely to be a target for development.

WCSB Unconventional Resources - CBM

The WCSB has very large in-place resources of CBM, located primarily in the plains of Alberta.[10] CBM was not the target of development in the WCSB until the start of the current decade, when higher gas prices and successful CBM development in the U.S. encouraged efforts to exploit these resources in Canada. With the recent development efforts, CBM production in Canada has increased from approximately 1.4 million m^3/d (50 MMcf/d) in mid-2003 to over 20.7 million m^3/d (730 MMcf/d) by the end of 2007.

The physical and gas producing characteristics of coals vary widely geographically and geologically from formation to formation. In this report, CBM in the various regions of western Canada is categorized as Horseshoe Canyon, Mannville, and Other. The Horseshoe Canyon main play accounts for the vast majority of CBM wells and represented about 84 percent of all CBM deliverability as of the end of 2007. Mannville CBM represented about 12 percent of all CBM deliverability as of year

10 Note that initial stages of testing for CBM prospects outside the WCSB is also underway, such as the Stellarton and Cumberland basins of Nova Scotia. Insufficient information is currently available to prepare deliverability projections for CBM outside the WCSB.

end 2007. The Other category includes CBM resources in the Belly River and Ardley formations of Alberta and CBM in B.C.

In development of Horseshoe Canyon CBM, coal intervals are often commingled with conventional sand intervals. All of these wells with CBM and conventional sands commingled are categorized as CBM in this report, so it should be recognized that the CBM deliverability estimates presented in this report include some contribution from the commingled conventional sands. Note that this approach differs from that of the Alberta Energy Resources Conservation Board (ERCB) where these components are estimated separately. The commingling of coal intervals with conventional sands at similar depth in the Horseshoe Canyon main play area has a beneficial effect on resource development, as the economics for the commingled group of zones are better than if the zones had to be segregated.

Consultations with industry have indicated lower expectations for future CBM development for reasons such as declines in the initial productivity of new wells, higher costs and concerns about obtaining access to CBM on freehold lands.

Unconventional Resources - Shale Gas

Shales with insufficient natural fracturing were generally bypassed until recently (Figure 2.3). With the advent of horizontal drilling to allow greater contact with the wellbore and the use of high pressure pumping to induce hydraulic fractures, development of formerly uneconomic shales could begin. Most spectacularly, the Barnett Shale near Fort Worth, Texas is now being extensively developed. After having only limited success with vertical wells in the early 1990s, wells are now

Canadian Shale Gas Areas

drilled using multi-leg horizontal wells from the same vertical wellbore, isolating sections of each horizontal leg to receive separate fracture treatments and performing micro-seismic testing to measure the orientation and extent of the induced fractures.

Efforts to evaluate two general types of shale gas projects are underway in western Canada. The first type involves deep horizontal wells with multi-stage fracture treatments. These are being attempted in northeast B.C. in the Horn River Basin and on the western side of the Montney tight gas play. The second type of project is the shallow Colorado shale activity in southeast Alberta and southwest Saskatchewan and features fairly low cost wells, commingled production and low cost access to existing infrastructure.

Outside of the WCSB, testing is also underway in the Utica shale in Quebec and on the Windsor Group shale in the Maritimes. Although still in the early stages, initial results in Quebec are reported as positive because of the shallow depth of the shale, the rock properties being comparable to more established shale plays, the high-quality gas and nearby access to major pipelines.

For this analysis, only the Horn River in B.C. and the Utica in Quebec are being represented as distinct shale gas plays. Due to the early stages of development and their commingled nature, activity in the Montney and Colorado shales has been included within the tight gas categories of these plays. Any shale gas production in the Maritimes within the projection period has been included in the onshore category containing the McCully Field.

2.2 Atlantic Canada

Gas production from Atlantic Canada consists mainly of output from the Sable Offshore Energy Project (SOEP) off the coast of Nova Scotia and the McCully Field in New Brunswick. Since 1999, the SOEP has produced marketable gas volumes in the range of 8.5 to 14.2 million m^3/d (300 to 500 MMcf/d), with production at the end of 2007 at 11.8 million m^3/d (415 MMcf/d). The project developer expects production will begin from the Deep Panuke project off the coast of Nova Scotia in late 2010.

The McCully Field in New Brunswick became a significant component of deliverability in Atlantic Canada in 2007 and was producing 0.8 million m^3/d (30 MMcf/d) at the end of 2007. Other onshore projects such as CBM in the Stellarton and Cumberland basins of Nova Scotia and shale gas opportunities in New Brunswick and Nova Scotia are in early stages of examination and are not expected to be significant contributors to deliverability within the projection period.

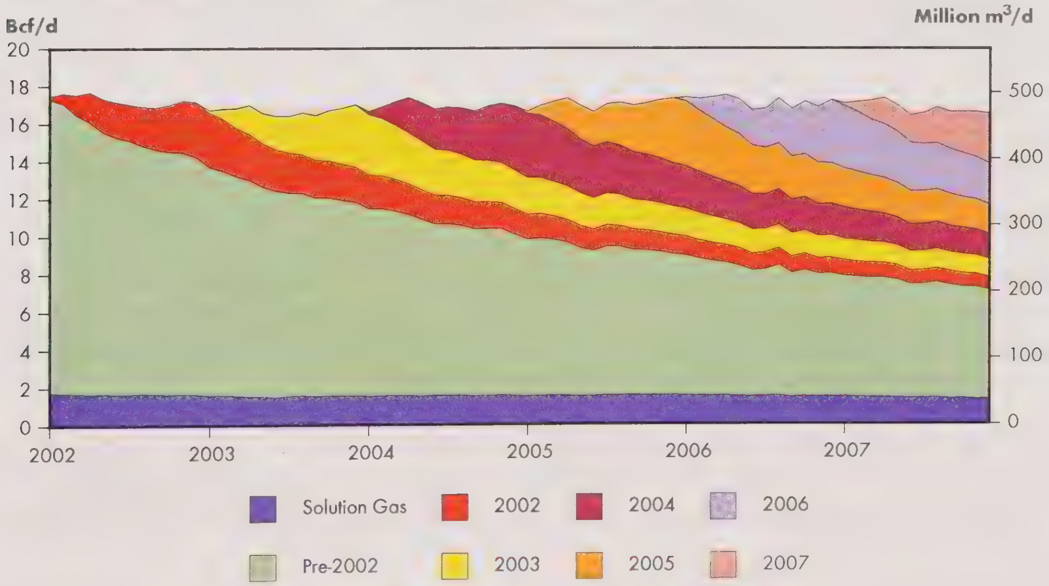
RECENT TRENDS

3.1 WCSB Historical Production and Development

Total WCSB historical gas production (conventional, tight gas and CBM) by connection year is shown in Figure 3.1. Gas production from the WCSB had been stable from about 2000 to mid-2007 at around 470 million m^3/d (16.6 Bcf/d) as high levels of drilling activity were able to offset the lower initial productivity of new wells and, in some cases, higher decline rates. As drilling failed to increase in 2006 and fell in 2007, production gradually declined in the second half of 2007 to finish the year about 20 million m^3/d (0.7 Bcf/d) lower than the level seen at the end of 2006. The importance of ongoing gas drilling activity to total production is evident with approximately half of all production at the end of 2007 coming from gas wells that came on stream over the previous four or five years.

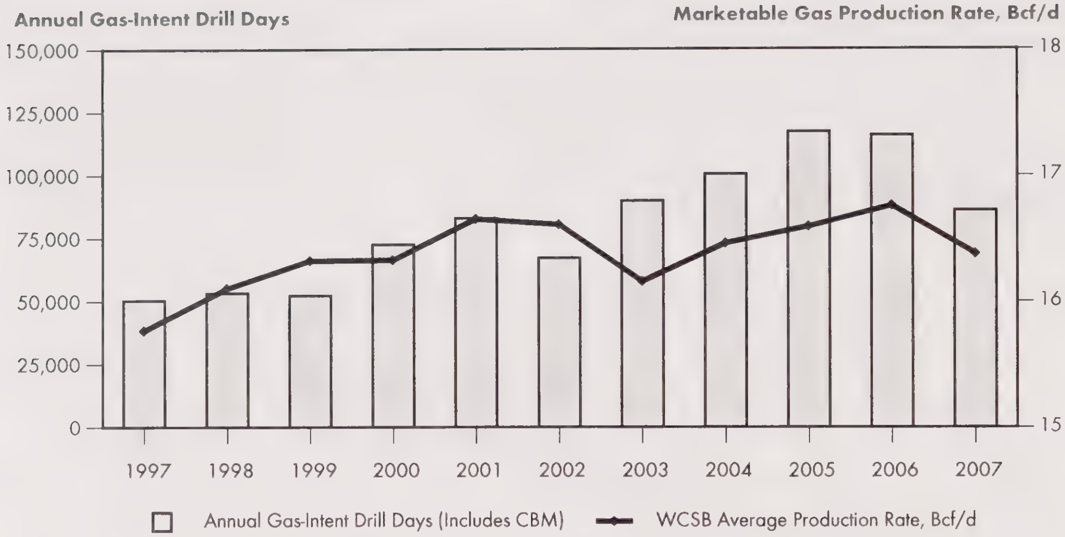
Throughout the 2000 to 2006 period of stable production, gas-intent drilling activity generally trended higher each year. Figure 3.2 shows the amount of gas-intent drilling (including tight gas, other conventional and CBM) that occurred in each year since 1996, and the average annual total deliverability in the WCSB over that period. In most years from 2000 through 2005, gas drilling activity was limited by the capacity of the Canadian rig fleet. During this period, increases in annual drilling activity were just able to maintain WCSB deliverability. After several years of steady growth, the amount of gas-intent drill days levelled off in 2006 and then dropped 35 percent in 2007.

WCSB Total Historical Gas Production by Connection Year



Source: NEB Analysis of GeoScout Well Data

WCSB Historical Annual Average Gas Production and Annual Gas-Intent Drill Days



Source: Board Analysis of GeoScout Well Data

Total oil and gas drilling activity in the first half of 2008 was similar to 2007, although an increasing share of the activity was being directed to oil. The corresponding reduction in natural gas-directed activity occurred despite an approximate doubling of natural gas prices over that period. The delayed investment response to higher natural gas prices likely reflects capital investment commitments for 2008 that were made in fall 2007 when natural gas prices were particularly low. Some capital investment increases were announced toward the middle of 2008, but it is unknown if the sudden sharp drop in natural gas prices in July might lead to a reallocation of the increase between natural gas and oil projects.

3.2 Costs to Develop New Gas Supplies in the WCSB

The relationship between development costs and natural gas price has had a strong influence on drilling activity in the WCSB.

A review of the economic factors influencing development of new gas supplies is useful to understand gas drilling activity levels in the WCSB. Capital expenditures are incurred in drilling each well, and if the well is successful, further capital costs are incurred to complete the well and connect it to processing facilities and the pipeline grid. Once the well comes on stream, the revenue generation commences. After reaching its initial production rate, the production rate of the well naturally declines. Throughout production, there are further costs incurred, mainly operating costs and royalties, until eventually the economic limit of operations is reached and the well is abandoned. For economic success, the revenue generated over the productive life must pay out all of the costs incurred for the well and provide the producer with a return on investment.

Full-cycle costs represent the total costs associated with a well. Through consultations and internal analysis,[11] full-cycle costs in the WCSB for 2007 were estimated to be about $7.88 per GJ. This is well above the average market price for natural gas in western Canada in 2007, estimated at $5.88 per

11 NEB Briefing Note, *Natural Gas Supply Costs in Western Canada in 2007*. Available at www.neb-one.gc.ca.

GJ.[12] This negative relationship between costs and price was roughly the same as in 2006 when costs were estimated at $8.00 and price at $6.22 (both per GJ).

Though it might seem illogical for any wells to have been drilled in 2006 and 2007 with average costs so far above market prices, there is a reasonable justification. Just as there is a wide range of gas prospects in western Canada, there is a wide range in the length of time that wells produce and in their cost. Similarly, prices can vary over the life of a well and be influenced by the choice to lock in future prices in advance through hedging or to accept the variability of daily spot markets. As a result of this variability in costs, prices and expectations, some drilling remains profitable even when average costs exceed average prices.

Between 2000 and 2005, except for 2002, the average price significantly exceeded the average of the sum of major costs. Also, in each of those years, drilling activity was very strong, with the rig fleet in the WCSB operating at close to maximum capacity. In 2002, when the price dipped down to approximately equal to the sum of the costs, drilling activity also declined markedly.

3.3 Other Trends and Events Pertinent to Gas Development

North America has experienced particularly high volatility in natural gas prices since the prices bottomed out last fall. As less LNG was imported into North America and oil prices surged, natural gas prices more than doubled from $4.42 in September 2007 to $9.81 in June 2008.[13] After peaking in early July at over $11, daily spot prices in Alberta dropped steadily to languish at around $7 in August.[14] This extreme price volatility makes upstream investment decisions more challenging and may result in companies taking a more cautious approach to natural gas plans for the rest of 2008 and into 2009 and 2010 than might have been the case when prices were rising earlier in the year.

Interest in shale gas is accelerating in Canada following the success of shale gas development in the U.S. Considerable interest is pouring into the combination shale/tight gas Montney play and into the Horn River shale play in northeast B.C. Early stages of investigation are also underway in shale gas prospects in Quebec and the Maritimes. While having massive potential, the viability of large scale commercial development of shale gas in Canada has yet to be proven. Companies have made major commitments in terms of land sales in the Montney and Horn River plays and are actively initiating drilling programs to investigate the extent and optimal operating practices for these shales. There is likely to be a need for additional pipeline capacity out of these regions and open seasons to solicit shipper interest have been initiated.

Though there has been a significant expansion of Canada's drilling fleet to almost 900 rigs, the availability of labour remains tight and industry consultations suggest that only an estimated 500 to 600 of these rigs could be staffed on a sustained basis. At activity levels approaching this 500 to 600 drilling rig threshold, drilling costs are likely to experience upward pressure and average efficiency could start to erode as less-experienced labour is introduced.

Despite the substantial surplus of drilling equipment in western Canada, additional newly built rigs are likely to continue to enter the rig fleet. These new rigs are "fit-for-purpose" units that may be of shallow, medium or deep capability, and have been specifically designed with features to optimize drilling into particular formations. The building of these rigs is commissioned under long-term take-or-pay contracts with specific exploration and production companies.

12 Estimate uses the Alberta Reference Price from: www.energy.gov.ab.ca/NaturalGas/1322.asp.

13 Alberta Reference Price in $ per GJ.

14 Daily spot prices for Nova Inventory Transfer in $ per GJ used due to reporting lag in Alberta Reference Price.

Surplus drilling rigs that cannot compete in terms of capability or drilling efficiency are currently being parked and eventually could be scrapped.

The surplus of drilling rigs in western Canada may benefit the pace of development in non-traditional areas such as Atlantic Canada and Quebec. High mobilization costs and the absence of an extensive well service sector remain key challenges in these regions.

Canadian drilling companies are continuing to expand into the U.S. market. Existing and newly built rigs are being used to fulfill U.S. contracts along with key rig staff such as rig managers and drillers. U.S. customers are reported to be keen to employ Canadian drilling equipment because of the professionalism of Canadian rig workers, efficiency of operations and a greater willingness to relocate than is typical of U.S. rig workers. It is reported that Canadian staff appreciate the less seasonal nature of U.S. drilling that allows for steadier work. To this point, the loss of experienced labour to the U.S. is not a concern, but this could change if drilling activity were to turn strongly upward in Canada in the future.

Competition for investment capital for upstream natural gas activity in Canada remains a challenge. The strength of crude oil prices is making oil sands, conventional and heavy oil operations in western Canada more attractive and encouraging deep water exploration drilling off Newfoundland. Technical advances to enhance commercial development of the Bakken oil play in Saskatchewan and North Dakota are drawing substantial investment and activity. As a result, the share of natural gas-intent drilling in western Canada slipped to 63 percent in 2007 compared to a high of 76 percent in 2005.

Natural gas investment in Canada also faces competition from natural gas basins in the U.S. Large independent companies such as Encana, Devon and Apache are heavily involved in unconventional natural gas plays in the U.S. and have the ability to redirect capital spending as required. This can also benefit new Canadian developments such as shale gas as companies cycle personnel between regions and transfer knowledge and experience from U.S. operations.

Within western Canada, the attraction of the Montney and Horn River plays in B.C. and the Bakken oil play in Saskatchewan are shifting land sales revenues from Alberta and into the adjacent provinces. The drop in land sales within Alberta may be indicative of there being no plans for major increases in activity anticipated over the 2008 to 2009 time period. Consultations reinforced that there were no major increases anticipated for shallow gas or CBM activity within the timeframe to 2010.

North American natural gas prices have not been high enough to attract LNG away from markets in Europe and Asia. Currently only 28 million m^3/d (1 Bcf/d) of LNG is being imported into North America despite the fact that import capacity has grown to over 310 million m^3/d (11 Bcf/d) in recent years. However, over the period of 2008 to 2010 an additional 140 million m^3/d (5 Bcf/d) of LNG supply is expected to come onto the global market. This may result in increased North American LNG imports, particularly in the summer months. Should this occur, it could put downward pressure on North American natural gas prices and possibly affect the economics of natural gas production in the U.S. and Canada.

Growth in U.S. natural gas production has been substantial in 2008 at up to 8 percent above levels in 2007. The majority of the growth is coming from the Rocky Mountains and shale gas plays in Texas, Louisiana, Arkansas and Oklahoma. The start up of the Independence Hub in the Gulf of Mexico also helped to offset or at least slow production declines in the offshore. Over the 2009 to 2010 period, supply growth in the Rockies may be slowed by a lack of available pipeline takeaway capacity, but shale gas activity is likely to remain strong and some additional deep water Gulf of Mexico projects should begin production. Additional growth in U.S. supply would tend to slow upward movements in

North American natural gas prices and lower economic margins for the upstream industry in Canada and the U.S.

The outlook for WCSB remains positive with respect to natural gas prospectivity, with an estimated remaining marketable resource base of over 5 800 billion m^3 (205 Tcf) of conventional, CBM, tight gas and shale gas.[15] There are likely to be additions to the marketable resource base as producers continue to develop the understanding and techniques to unlock these resources. However, recent supply cost studies and general industry sentiment suggests that natural gas prices in western Canada may need to exceed $8 and perhaps even $9 per GJ before margins would be sufficient to encourage higher levels of drilling.

After many years with an increasing focus on shallow gas and CBM, the industry in western Canada has significantly reduced its shallow gas activity and has been drilling a greater number of deeper targets on the west side of the basin. The average depth per gas well in the WCSB in 2007 was approximately 1 109 metres, compared to around 960 metres in 2003.

On the east coast, Sable gas production continues to be supported by the compression facilities added in 2007. The Deep Panuke offshore field is under development and is scheduled to enter service in late 2010. Development of the onshore McCully field is continuing in New Brunswick.

15 National Energy Board EMA, *Canada's Energy Future*, 2007, Table A4.1. Available at www.neb-one.gc.ca. updated to the end of 2007 by deducting an estimated 527 billion m3 (18.6 Tcf) produced from 2005 to 2007.

Overview of Cases

The objective of the cases used in this analysis is to reflect a reasonable range of uncertainty for Canadian natural gas deliverability over the 2008 to 2010 period. The biggest uncertainty over this period is considered to be the North American natural gas price. The range of prices experienced during the extremely volatile 12 months from September 2007 through August 2008 provides an excellent example of a potential range of prices considered to be reasonable over the 2008 to 2010 period.

Based on consultations and the Board's internal analysis, it appears that market prices in western Canada between $8 and $9 per GJ would provide the industry with adequate returns to incent gradually increasing levels of drilling. This might help to compensate for gradual declines in well performance and hold deliverability at a fairly constant level. As market prices increased to $11 per GJ by July 2008, a number of companies announced significant increments to their capital spending intentions. Conversely, price expectations in the $6 to $7 per GJ range in the fourth quarter of 2007, led to a pullback in natural gas investment.

Other factors that affect the level of drilling activity include drilling costs and the capacity of the drilling rig fleet. These factors tend to be related. Higher utilization leads to higher costs as more labour must be attracted and retained. As less experienced staff is added, efficiency tends to drop and costs increase further. The availability of materials such as tubulars and services such as pressure pumping, cementing and testing also contribute to lower efficiency and higher costs. Costs have been assumed to move in one direction over the period and that is to become gradually higher because of the influence of labour constraints and of external costs for materials such as steel, cement and fuel. This reflects costs increasing from levels where they paused in 2007 as utilization dropped. Threshold levels for drilling utilization (the 500 to 600 rig limit in 2008) were not breached in any of the cases.

Another factor is the erosion in well performance over time as the prime prospects tend to be developed first and subsequent developments access less productive prospects. Advances in technology can extend the inventory of prospects. An example is the current interest in gas shales that had been bypassed for decades as unproductive until advanced horizontal drilling and hydraulic fracturing techniques were developed to unlock some of their potential. Well performance trends are clearly established in a mature producing area like western Canada and were not varied among the cases. Performance of shale gas wells represents a greater uncertainty, but the shortage of information from which to develop a reasonable range led the Board to maintain a single estimate.

Finally, there is the potential for shifts in activity between regions and different types of prospects. Such a shift occurred in the late 1990s when there was a significant move to develop shallow gas in western Canada that resulted in a dramatic increase in the number of wells drilled and a drop in the productivity of the average well. Later this was followed by a strong move into CBM. In the period to 2010, the extent of the move into the Montney and Horn River shale plays represents the key potential shift of this type. Over this relatively short time period, the limited ability to construct

additional pipeline infrastructure restricts the upside of shale gas development. The extent of CBM development represents another potential variable. Consultations indicated that it is unlikely that there will be significant variation in the expected level of shallow gas drilling.

Three cases have been developed to represent a reference, high and low range to Canadian deliverability for the period to 2010. These cases are differentiated primarily in terms of North American natural gas price as indicated by varying levels of capital investment. The cases also vary in terms of CBM activity and drilling levels in the Montney and Horn River plays. Deliverability in areas outside western Canada was adjusted to reflect the general reference, high and low themes of the cases. A summary of the key assumptions used in the cases is provided in Table 4.1.

Summary of Case Assumptions

	2007	Reference Case			High Case			Low Case		
		2008	2009	2010	2008	2009	2010	2008	2009	2010
Alberta reference price ($ per GJ)	$5.88	$9.00	$9.00	$9.00	$11.00	$11.00	$11.00	$7.00	$7.00	$7.00
Natural gas drilling investment ($ millions)	11,158	11,110	12,874	14,558	12,879	18,155	19,304	10,904	11,553	12,338
Natural gas-intent drill days	75,672	74,476	78,456	82,912	82,960	106,819	109,946	71,287	70,404	70,269
Natural gas-intent wells drilled	12,515	11,792	12,139	12,298	13,070	16,966	16,778	11,384	11,027	10,991
Montney tight gas wells	138	240	275	300	260	300	350	150	125	100
Horn River shale gas wells	0	15	50	150	25	75	200	15	50	45
CBM wells drilled	1,759	1,671	1,587	1,508	1,759	2,606	2,606	1,407	1,126	901

Assumptions Common to All Cases	**2007**	**2008**	**2009**	**2010**	**2008**	**2009**	**2010**	**2008**	**2009**	**2010**
Gas share of drill days	63%	62%	65%	70%	62%	65%	70%	62%	65%	70%
Cost per drill day ($ thousands)	142.1	149.2	164.1	175.6	149.2	164.1	175.6	149.2	164.1	175.6
Total drilling rig fleet	879	891	903	915	891	903	915	891	903	915

METHODOLOGY

Canadian natural gas deliverability over the projection period will consist of conventional gas supply from the WCSB with contributions from Atlantic Canada and other Canadian sources and growing CBM production from Alberta. In this report, trends in well production characteristics and resource development expectations are assessed to determine parameters that define future natural gas deliverability from the WCSB. A different approach is used for Atlantic Canada where production is sourced from a very small number of wells.

Rather than presenting these technical procedures and detailed results in the body of this report, this information is made available in the following Appendices:

A. Methodology Applied and Resulting Parameters

    1. Methodology (Detailed Description)

    2. Deliverability Parameters - Results

    3. Group Performance Parameters for Existing Connections

    4. Historical and Projected Average Connection Parameters

B. Drilling Projection Details

    1. Factors for Allocation of Gas-Intent Drill Days to Areas

    2. Detailed Drilling and Connection Projections for Cases

The parameters obtained from the analysis performed for this report were fed into a model to produce the deliverability projections. As discussed in Chapter 4, market conditions create considerable uncertainty in the drilling activity that will occur in the WCSB, so deliverability projections were made for three different cases of gas drilling activity. These projections are presented in Chapter 6 of this report.

Deliverability Outlook

Three deliverability projection cases were analysed in this report—Reference Case, High Case and Low Case. The cases reflect different levels of natural gas investment and drilling activity over the projection period. The Board's deliverability outlook by area/resource for the Reference Case is shown in Table 6.1. Similar tables for the High Case and Low Case are available in Appendix C.

Table 6.1 shows annual average production for 2007 and expected annual average deliverability for 2008, 2009 and 2010 in the Reference Case for each grouping. Canadian annual average deliverability is expected to decrease from 477 million m^3/d (16.9 Bcf/d) in 2007 to 450 million m^3/d (15.9 Bcf/d) in 2010.

The major components of the deliverability projection are described in more detail in the sections below.

6.1 WCSB – Reference Case

Total WCSB deliverability in the Reference Case is projected to decrease from 465 million m^3/d (16.4 Bcf/d) in 2007 to 440 million m^3/d (15.5 Bcf/d) in 2010 as overall declines in conventional gas deliverability more than offset projected increases in deliverability from CBM, shale gas and tight gas in the Alberta Deep Basin and B.C. Deliverability slips most in 2008 with a drop of 16.7 million m^3/d (0.6 Bcf/d) and then begins to stabilize with losses of 6.9 million m^3/d (0.2 Bcf/d) in 2009 and only 1.5 million m^3/d (0.1 Bcf/d) in 2010.

Figure 6.1 shows the Reference Case deliverability projection for conventional gas in the WCSB broken down by area. With only modest increases in drilling activity in this case, conventional gas deliverability is projected to decline by 34 million m^3/d (1.2 Bcf/d) from 2007 to 2010. Excluding the contribution from tight gas, the remainder of the conventional gas component is projected to decline more severely by 65 million m^3/d (2.2 Bcf/d) from 2007 to 2010.

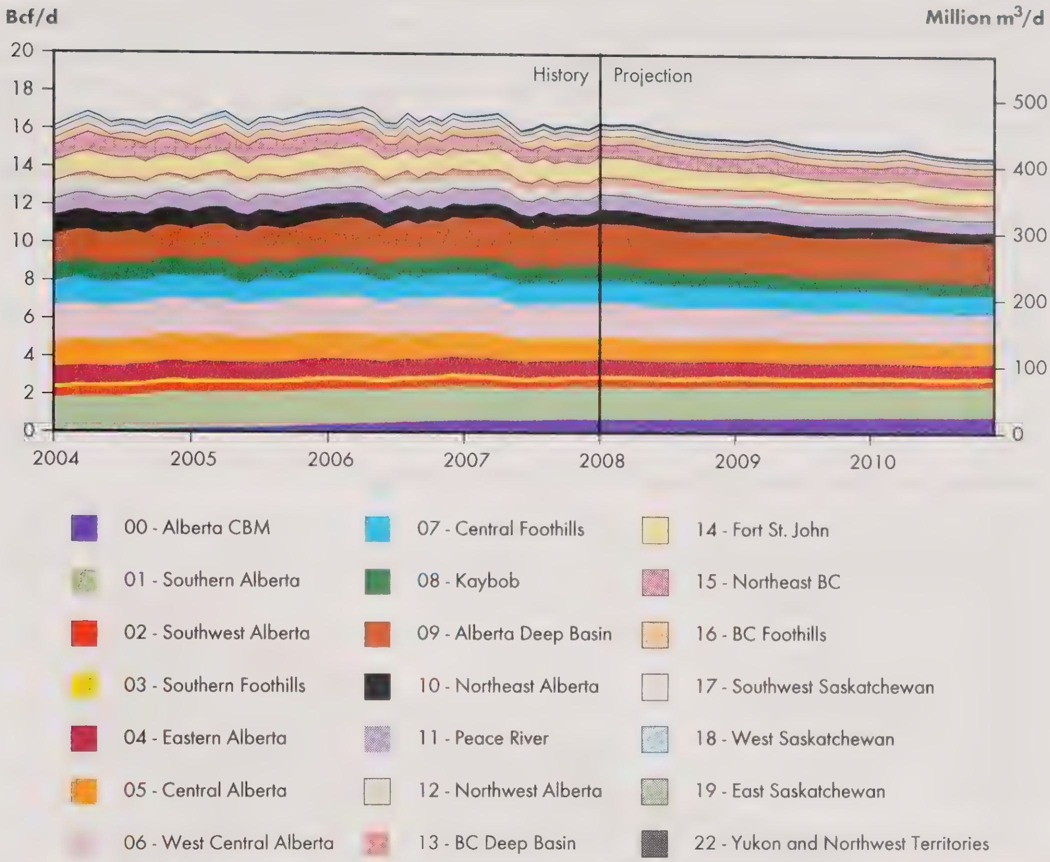
Alberta deliverability drops by almost 47 million m^3/d (1.7 Bcf/d) over the period despite a gain of 5 million m^3/d (0.2 Bcf/d) in CBM deliverability. CBM deliverability rises despite the assumption that CBM drilling will decline by 5 percent annually. This is achieved because the production rates of CBM wells decline very slowly and less of the production from new wells is required to offset declines on existing wells. The projection of CBM deliverability is shown in Figure 6.2. Overall Alberta conventional gas deliverability declines at an average of about 5 percent per year as gas drilling remains relatively flat over the period.

In the Reference Case, British Columbia deliverability rises dramatically on the strength of growing Montney and Deep Basin output that adds almost 27 million m^3/d (0.9 Bcf/d) to deliverability over the period as shown in Figure 6.3. Note that this projected increase is likely at the upper limits of pipeline infrastructure serving these areas, and not all of the increment may be able to be produced.

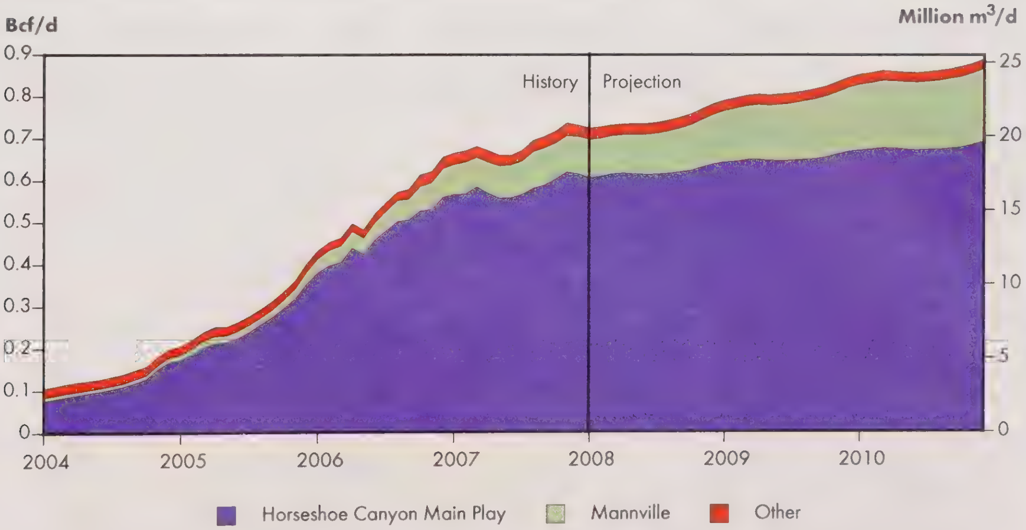
Canadian Gas Deliverability Outlook by Area/Resource – Reference Case

Area/Resource	Historical		Projection					
	2007		2008		2009		2010	
	$10^6m^3/d$	MMcf/d	$10^6m^3/d$	MMcf/d	$10^6m^3/d$	MMcf/d	$10^6m^3/d$	MMcf/d
00 - Alberta CBM	19.50	688	21.08	744	23.02	813	24.49	864
HSC Portion	16.45	581	17.51	618	18.44	651	19.18	677
Mannville Portion	2.31	82	2.86	101	3.91	138	4.68	165
Other CBM Portion	0.73	26	0.71	25	0.67	24	0.62	22
01 - Southern Alberta	48.87	1,725	47.86	1,690	47.45	1,675	46.85	1,654
Tight Portion	32.70	1,154	31.81	1,123	31.17	1,100	30.57	1,079
02 - Southwest Alberta	11.18	395	10.43	368	9.60	339	8.90	314
Tight Portion	3.13	111	2.85	101	2.54	90	2.28	81
03 - Southern Foothills	4.91	173	5.10	180	5.11	180	5.03	177
04 - Eastern Alberta	25.19	889	22.83	806	20.50	724	18.72	661
Tight Portion	0.59	21	0.52	18	0.46	16	0.41	15
05 - Central Alberta	34.77	1,227	31.09	1,098	29.08	1,026	27.76	980
Tight Portion	2.45	86	2.12	75	2.09	74	2.05	72
06 - West Central Alberta	50.50	1,783	47.56	1,679	43.90	1,550	41.04	1,449
Tight Portion	12.93	456	12.65	446	11.85	418	11.27	398
07 - Central Foothills	33.72	1,190	32.35	1,142	30.79	1,087	29.49	1,041
Tight Portion	1.22	43	1.21	43	1.22	43	1.24	44
08 - Kaybob	25.54	901	24.05	849	22.23	785	20.86	736
Tight Portion	8.43	298	7.67	271	7.01	248	6.48	229
09 - Alberta Deep Basin	60.26	2,127	59.12	2,087	59.72	2,108	60.64	2,141
Tight Portion	37.40	1,320	46.90	1,656	47.11	1,663	47.79	1,687
10 - Northeast Alberta	19.44	686	16.41	579	14.06	496	12.19	430
11 - Peace River	21.54	760	20.11	710	18.56	655	17.52	618
12 - Northwest Alberta	16.54	584	14.46	511	12.91	456	11.66	411
13 - BC Deep Basin	10.84	383	11.17	394	12.47	440	13.64	482
Montney Portion	0.00	0	0.84	29	1.96	69	2.91	103
Other Tight Portion	7.18	254	7.18	254	7.73	273	8.16	288
14 - Fort St. John	30.13	1,064	34.71	1,225	42.59	1,504	50.66	1,788
Montney Portion	0.00	0	6.11	216	16.14	570	25.66	906
15 - Northeast BC	19.96	705	20.65	729	22.64	799	25.71	907
Horn River Shale	0.00	0	0.27	9	1.11	39	3.56	126
Tight Portion	11.54	407	13.09	462	14.60	515	15.60	551
16 - BC Foothills	12.63	446	11.79	416	10.98	388	10.30	364
17 - Southwest Saskatchewan	10.80	381	9.87	348	8.95	316	8.23	291
Tight Portion	10.20	360	9.26	327	8.36	295	7.66	270
18 - West Saskatchewan	6.32	223	5.47	193	4.85	171	4.38	154
19 - East Saskatchewan	1.19	42	1.25	44	1.22	43	1.18	42
22 - Yukon and Northwest Territories	0.89	32	0.63	22	0.45	16	0.32	11
Total Conventional	**445.23**	**15,717**	**426.67**	**15,061**	**416.97**	**14,719**	**411.52**	**14,527**
Total Tight Portion	**127.77**	**4,510**	**142.21**	**5,020**	**152.24**	**5,374**	**162.07**	**5,721**
Total CBM	**19.50**	**688**	**21.08**	**744**	**23.02**	**813**	**24.49**	**864**
Total Shale	**0.00**	**0**	**0.27**	**9**	**1.11**	**39**	**3.56**	**126**
Total WCSB	**464.73**	**16,405**	**448.01**	**15,815**	**441.10**	**15,571**	**439.57**	**15,517**
Atlantic Canada	12.07	426	13.54	478	10.71	378	8.38	296
Other Canada	0.67	24	0.65	23	0.63	22	1.74	62
Total Canada	**477.47**	**16,855**	**462.20**	**16,316**	**452.44**	**15,971**	**449.69**	**15,874**

WCSB Conventional Deliverability – Reference Case



CBM Deliverability by Formation– Reference Case



The contribution from Horn River shale gas deliverability is projected to be modest over the period averaging 4 million m^3/d (0.1 Bcf/d) in 2010 as development of the play scales up and additional infrastructure becomes available. Outside of the Montney play, B.C. conventional gas is in decline at

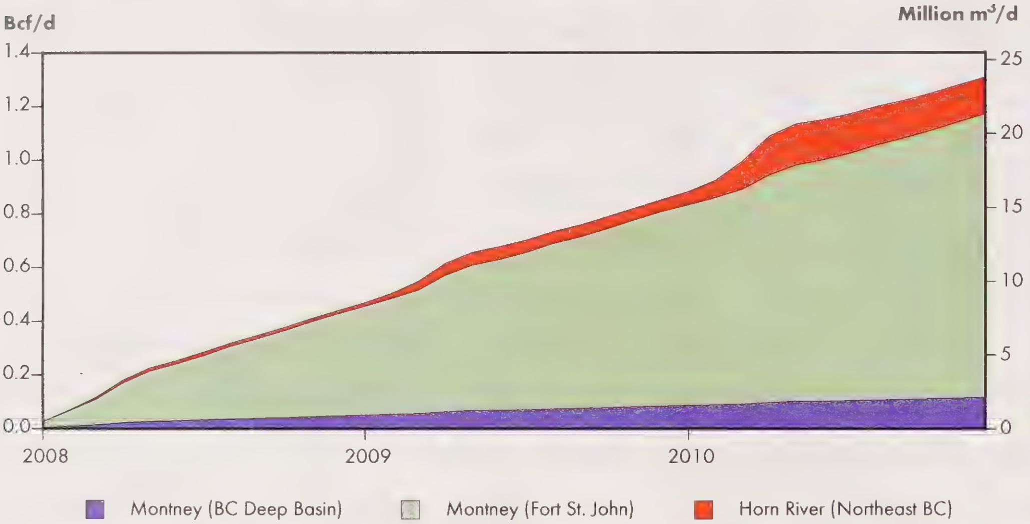
about 5 percent per year. Natural gas-intent drilling in B.C. is projected to rise at about 12 percent annually in the Reference Case to reach almost 1 260 wells drilled in 2010.

Natural gas drilling in Saskatchewan is projected to drop by roughly 17 percent in 2008 and recover only slightly over the following two years as attention in the province continues to focus on the Bakken oil play. This causes Saskatchewan natural gas deliverability to slip by an average of 9 percent a year to be 4.5 million m^3/d (0.2 Bcf/d), lower in 2010 than in 2007.

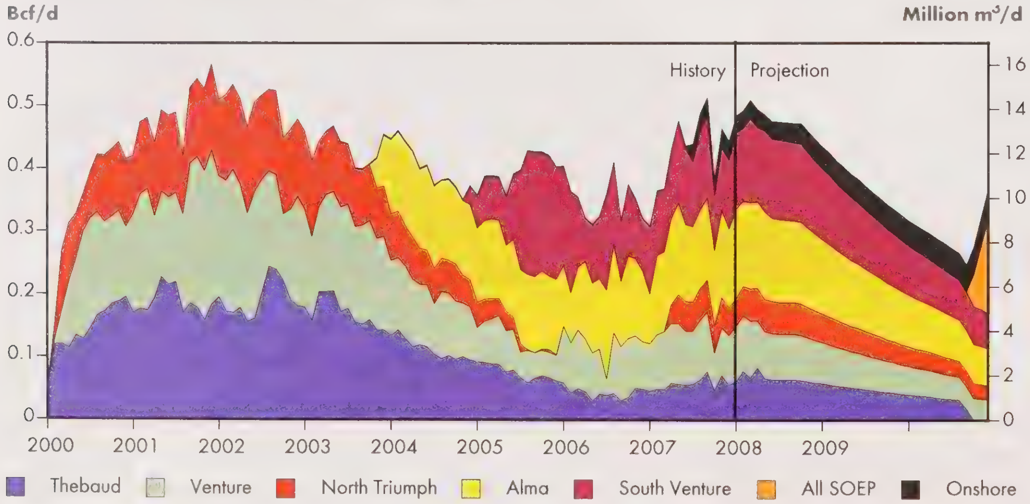
6.2 Atlantic Canada

As indicated in Figure 6.4, deliverability from Atlantic Canada continues to benefit from the compression addition at the Sable project and the ongoing development of the McCully field in New Brunswick. Deliverability is projected to remain relatively steady to the end of 2008 to average

Montney and Horn River Deliverability – Reference Case



Atlantic Canada Deliverability – Reference Case



13.5 million m³/d (0.48 Bcf/d). After 2008, production declines are projected to resume. Start up of the Deep Panuke project is projected for the last quarter of 2010 and begins to offset some of the drop in Sable production. Deep Panuke is expected to reach its design production rate of around 8.5 million m³/d (0.3 Bcf/d) in 2011.

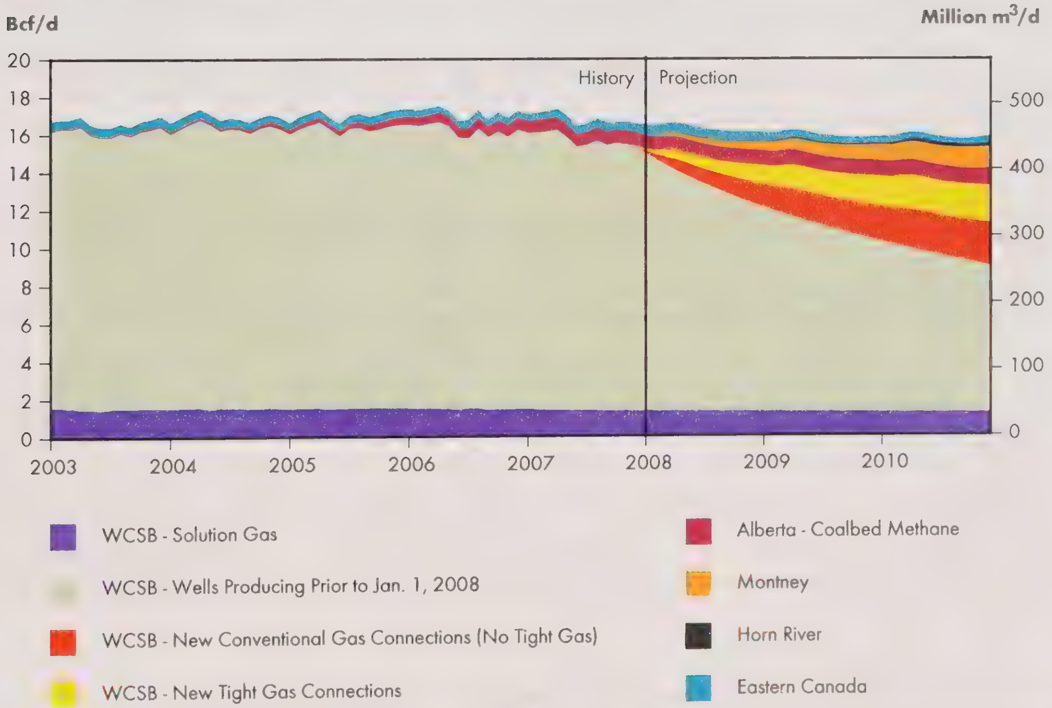
6.3 Other Canada

The Reference Case projection of deliverability in the remainder of Canada consists primarily of Ontario, Quebec and northern portions of the Northwest Territories. Projected deliverability from these regions remains relatively constant to 2010 with the exception of the assumption of an estimated 1.1 million m³/d (0.04 Bcf/d) of shale gas production in Quebec by 2010. Due to the early stage of investigation into shale gas development in Quebec, this projection is highly speculative at this time. Production from Ontario is projected to continue at around 0.6 million m³/d (0.02 Bcf/d) over the period.

6.4 Total Canada

Figure 6.5 portrays the Reference Case outlook for total Canadian gas deliverability split into major segments of gas supply over the projection period. Total Canadian deliverability is expected to decrease in 2008 and then move to more stable conditions in 2009 and 2010. Although natural gas drilling increases only modestly over the period, the increased focus on higher productivity wells in northeast B.C. and the Alberta portion of the Deep Basin helps to offset much of the ongoing declines in other conventional gas areas. Different market conditions that may occur cause uncertainty, as lower or higher drilling levels would significantly impact the deliverability expected from new gas connections. Charts similar to Figure 6.5 showing the deliverability projections for the High Case and Low Cases are available in Appendix C.

Outlook for Canadian Gas Deliverability – Reference Case



6.5 Summary of Deliverability Cases

Deliverability projections were prepared for the Reference Case and two alternative cases to reflect the uncertainty surrounding North American natural gas prices and the corresponding economics of natural gas drilling in Canada. Table 6.2 summarizes the total Canadian annual average deliverability under each case, and Figure 6.6 is a chart showing the deliverability for the three cases and the historical production. Canadian deliverability is projected to decrease in the Reference and Low cases. In the Reference Case, average annual deliverability is expected to slip from 477 million m^3/d (16.9 Bcf/d) in 2007 to 450 million m^3/d (15.9 Bcf/d) in 2010. Under the reduced drilling of the Low Case, deliverability is projected to decline to 426 million m^3/d (15.0 Bcf/d). After falling in 2008, deliverability is projected to increase in 2009 and 2010 in the High Case and would average 489 million m^3/d (17.3 Bcf/d) by 2010.

6.6 Key Differences from Previous Projection

Northeast B.C. – Since the Board's 2007 report,[16] shale gas and tight gas prospects in the Horn River and Montney plays of northeast B.C. have attracted significant interest from Canada's upstream industry. Favourable test results reported from initial wells, major interest in land sales and open seasons for new pipeline capacity are all indications of the potential significant impact on deliverability from these areas. This report provides estimates of drilling and deliverability that are based on very limited available data and on analogues from a U.S. shale play, and the reader is cautioned on the speculative nature of these estimates.

North American Natural Gas Price Volatility – Over the 12 month period from September 2007 to August 2008, North American natural gas prices have swung from $5 to $11 and back to $7 per GJ. Over the 2008 summer, crude oil prices have spiked to record levels and then dropped dramatically. In such a volatile pricing environment, projections of Canadian natural gas drilling investment are highly uncertain. A range of natural gas prices were considered in the development of the three cases in this report.

Stabilizing of Canadian Deliverability after 2008 – The 2007 report projected that Canadian deliverability would continue to decline in all three cases. In this report, prospects of growth in tight gas and shale gas developments in northeast B.C. provide the potential for a stabilization or even modest increase in deliverability over the period

Deliverability Summary for Cases

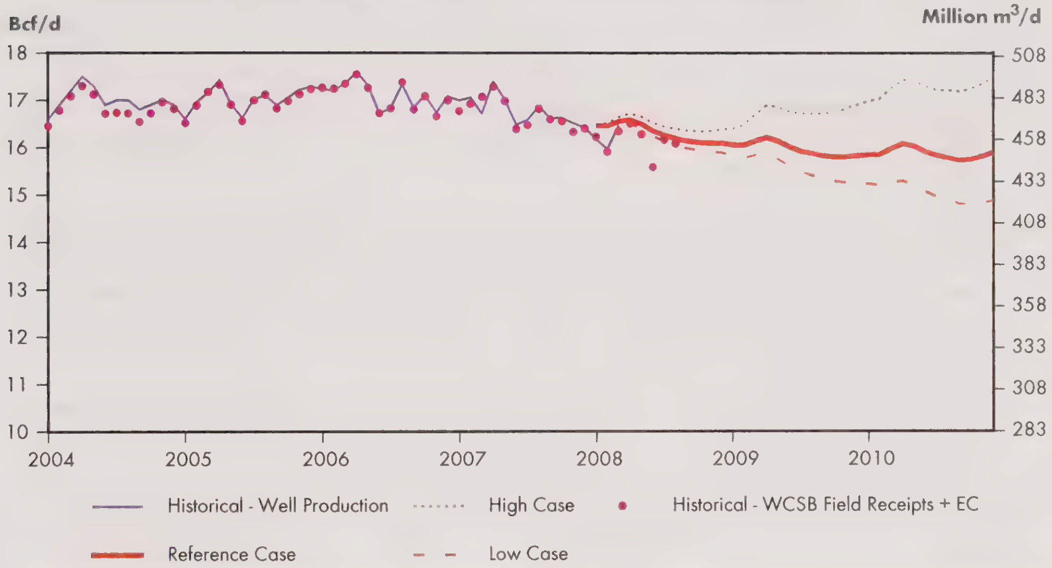
	Historical Production		Deliverability Projections					
			Low Case		Reference Case		High Case	
	10^6m^3/d	Bcf/d	10^6m^3/d	Bcf/d	10^6m^3/d	Bcf/d	10^6m^3/d	Bcf/d
2007	477.5	16.85	-	-	-	-	-	-
2008	-	-	459.0	16.20	462.2	16.32	467.0	16.49
2009	-	-	440.9	15.56	452.4	15.97	473.8	16.72
2010	-	-	426.0	15.04	449.7	15.87	488.9	17.26

16 NEB EMA, *Short-term Canadian Natural Gas Deliverability 2007-2009*, Available at www.neb-one.gc.ca.

6.7 Canadian Deliverability and Canadian Demand

The Board's outlooks for gas deliverability and Canadian gas demand over the projection period are included in Table 6.3 to provide market context for the relative changes in gas deliverability. Total Canadian annual gas demand is expected to grow from 243 million m^3/d (8.6 Bcf/d) in 2007 to 247 million m^3/d (8.7 Bcf/d) in 2010. In the Reference Case, gas deliverability is projected to decrease by 28 million m^3/d (1.0 Bcf/d) over the same period.

Outlook for Canadian Gas Deliverability – Comparison of Cases



Average Annual Canadian Deliverability and Demand

	2007		2008		2009		2010	
	$10^6m^3/d$	Bcf/d	$10^6m^3/d$	Bcf/d	$10^6m^3/d$	Bcf/d	$10^6m^3/d$	Bcf/d
Canadian deliverability, Reference Case	477.5	16.85	462.2	16.32	452.4	15.97	449.7	15.87
Western Canada Demand	136.9	4.83	136.1	4.81	138.6	4.89	138.4	4.89
Eastern Canada Demand	106.5	3.76	104.5	3.69	105.4	3.72	108.8	3.84

Conclusions

- Western Canada will remain the source for approximately 98 percent of Canadian gas production from 2008 to 2010. Atlantic Canada accounts for most of the remaining 2 percent of Canadian gas production, with deliverability expected to decline in 2009 and begin to recover late in 2010.
- North American natural gas prices have been particularly volatile over the 12 month period from September 2007 to August 2008, swinging from \$5 to \$11 and back to \$7 per GJ. Under conditions of such extreme price volatility, future levels of natural gas investment by the upstream industry are highly uncertain.
- Interest in shale and tight gas prospects in the Horn River and Montney plays of northeast B.C. has increased substantially in 2008. Although presently at far too early a stage in development to make a robust determination, should these northeast B.C. shales ever approach the multi-Bcf/d output of the major Barnett Shale play in the U.S., their impact could dramatically alter previous projections of decline for the WCSB.
- The contribution of shale gas over the period to 2010 is likely to be constrained by the need to test alternative approaches, assess commercial viability, optimize operations and build the infrastructure needed to move the shale gas to major pipelines.
- Interest in shale gas and tight gas may also be contributing to slowing growth of Canadian CBM activity.
- Increased competition for investment from oil and oil sands activity and from U.S. unconventional gas plays will present challenges for the recovery of natural gas investment in Canada.
- Prices in western Canada of \$8 to \$9 per GJ are likely required to maintain or accelerate current drilling levels.
- In 2008 North American natural gas prices have not been high enough to attract LNG away from markets in Europe and Asia and caused North American LNG imports to fall back to roughly 28 million m^3/d (1 Bcf/d) despite a more than doubling of import capacity. A large increment of up to 140 million m^3/d (5 Bcf/d) of new LNG supply is expected to enter service over the 2008 to 2010 period. Should this increase not be fully absorbed outside North America, significantly greater LNG imports could lower economic margins for the upstream industry in Canada and the U.S.
- Growth in U.S. natural gas production has been substantial in 2008 at up to 8 percent above the previous year. Further supply growth in the Rockies may be slowed by a lack of pipeline capacity, but shale gas activity is likely to remain strong and could dampen future price increases.
- The Canadian drilling rig fleet has expanded dramatically to close to 900 rigs, but labour shortages might only allow 500 to 600 to be staffed on a sustained basis. Upward cost pressures are re-emerging and would accelerate at activity levels approaching this 500- to 600- rig threshold.

- Costs also rise in response to a decreasing finding rate. The decreasing finding rate is a reflection of the lower initial productivity of new gas wells.
- Three cases were developed to account for a reasonable range of investment and drilling activity that may occur in western Canada over the projection period:
    - In the Reference Case, average annual natural gas deliverability is expected to slip from 479 million m^3/d (16.9 Bcf/d) in 2007 to 450 million m^3/d (15.9 Bcf/d) in 2010.
    - Projected Canadian natural gas deliverability in 2010 ranged from 426 million m^3/d (15.0 Bcf/d) in the Low Case to 489 million m^3/d (17.3 Bcf/d) in the High Case based on alternative levels of drilling.

Glossary

Average connection	An average connection applies to gas connections (either conventional or CBM) and represents the average producing characteristics of ALL connections for a geographic area and connection year. Production data for the average connection for any grouping (geographic area/connection year) is calculated as: [total production for all connections in grouping, summed by normalized production month]/ [the total number of connections in the grouping].
Canadian rig fleet	Drilling rigs that are listed in the Nickle's Energy Group weekly Rig Locator Report.
Connection	A completion in a geological horizon (or horizons) within a well for which oil and/or natural gas production is reported.
Connection year	The year associated with the "On Production Date" for a connection.
Conventional gas	Refers to natural gas from all sources other than CBM.
Decline rate	The decrease in production rate over time as a resource is depleted. There are various ways of expressing decline rates, and in this report exponential decline is the type used to define well production decline characteristics. With exponential decline, a straight line is exhibited when production rate is plotted against cumulative production, and the slope of the line defines the nominal decline rate (in this report it is expressed as fraction per year). Another way of expressing decline rate is in terms of effective decline rate, which is the decrease in production divided by the initial production rate. The effective decline rate can be converted into nominal terms using the equation: nominal decline rate = -ln(1 – effective decline rate)
Deep rig(s)	Drilling rigs with a depth capacity greater than 3 050 m.
Deliverability	The amount of natural gas a well, reservoir, storage reservoir or producing system can supply at a given time.
Depth capacity	The depth capacity (metres) for each drill rig as listed on the weekly Rig Locator Report published by Nickle's Energy Group.
Drill day(s)	The number of days that a rig is engaged drilling a well, calculated as drilling completion date minus the spud date plus 1.

Existing connections	Connections on production prior to 1 January 2008.
Finding rate	The amount of energy developed per effort or investment—for example, GJ per drill day.
Future connections	Connections on production after 1 January 2008.
Gas connection	A connection for which natural gas production has been reported, and where that production is deemed to be gas (either conventional or CBM). If the connection has oil and gas production, the ratio of cumulative gas production to cumulative oil production is used to classify the connection as gas or oil.
Gas well	A wellbore with one or more geological horizons capable of producing natural gas.
Gas-intent drilling	Applies to drilling, drill days or wells deemed by the NEB to be undertaken for the purpose of exploiting gas resources, excluding solution gas.
Horseshoe Canyon main play area	A collection of townships in Central Alberta intended to approximately reflect the areas of the Horseshoe Canyon Coal zone where gas concentration >2 Bcf per section as presented in "U2 Figure 27 - Gas Concentration (Bcf/Section) within the Horseshoe Canyon Coal Zone" from the *Natural Gas Potential in Canada 2005 - Volume 4*, published by the Canadian Gas Potential Committee (CGPC), and where formation depth is less than 1 000 m.
Marketable gas	Natural gas that has been processed to remove impurities and natural gas liquids. It is ready for market use.
Medium rig(s)	Drilling rigs with a depth capacity greater than 1 850 m and less than or equal to 3 050 m.
Normalized production month	For any gas well connection and for any production month, the normalized production month is the number of months since the first month of production for the gas well connection.
Oil connection	A connection for which oil production has been reported and where that production is deemed NOT to be associated with oil sands. If the connection has oil and gas production, the ratio of cumulative gas production to cumulative oil production is used to classify the connection as gas or oil.
Projection period	January 1 2008 to December 31 2010
Rig categories	The groupings of shallow, medium and deep drill rigs in the WCSB Rig fleet, based on depth capacity.
Rig day(s)	Each day of the year for each drilling rig represents a rig day. The annual allocation of the rigs in the WCSB rig fleet to the various study areas results in an aggregate number of annual rig days for each area.
Shallow rig(s)	Drilling rigs with a depth capacity less than or equal to 1850 m.
Solution gas	Natural gas that is produced from an oil well connection.
Study area(s)	The areas of the WCSB defined in Figure 2.2 of this report.

Available at http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/ntrlgsdlvrblty20082010/ntrlgsdlvrblty20082010-eng.html

A. Methodology Applied and Resulting Parameters

1. Methodology (Detailed Description)
2. Deliverability Parameters - Results
3. Group Performance Parameters for Existing Connections
4. Historical and Projected Average Connection Parameters

B. Drilling Projection Details

1. Factors for Allocation of Gas-Intent Drill Days to Areas
2. Detailed Drilling and Connection Projections for Cases

C. Deliverability Details for High and Low Cases

1. High Case
2. Low Case